CHAPTER IV

RESPONSES TO CPUC DATA REQUESTS

SAN DIEGO GAS AND ELECTRIC COMPANY (U 902 G)

RESPONSES TO CPUC DATA REQUESTS

OIR TO ESTABLISH POLICIES AND RULES TO ENSURE RELIABLE, LONG-TERM SUPPLIES OF NATURAL GAS TO CALIFORNIA

R.04-01-025

QUESTION 1

Please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 Your Utility's demand forecasts for its service territory under the following scenarios. [1]

a. Average Year Scenarios
   - i. Average Year
   - ii. Average Year + 10%
   - iii. Average Year + 20%

b. Abnormally Cold Year Scenarios
   - i. 1 in 10 years
   - ii. 1 in 10 years + 10%
   - iii. 1 in 35 years
   - iv. 1 in 35 years + 10%

c. Abnormally Dry Year Scenarios
   - i. 1 in 10 years
   - ii. 1 in 10 years + 10%
   - iii. 1 in 35 years
   - iv. 1 in 35 years + 10%

d. Abnormally Cold and Dry Year Scenarios
   - i. 1 in 10 years
   - ii. 1 in 10 years + 10%
   - iii. 1 in 35 years
   - iv. 1 in 35 years + 10%

RESPONSE 1

See Table Q.1 for the demand forecasts for all of the above scenarios. The data is provided for Total Demand and also shown for Core Demand, Noncore Non-EG Demand and EG Demand.

Forecasted annual demand for 2006 and 2016 is shown in columns (a) and (b), respectively. Annual demand expressed on an MMcfd basis for 2006 and 2016 is shown in columns (c) and (d), respectively. SDG&E has also provided forecasted peak-day demand for 2006 and 2016. This is shown in columns (e) and (f), respectively. The later was not specifically requested but this information is relevant in responding to Question 2 of the Commission's Data Request.

In preparing these demand forecasts, SDG&E made use of certain existing modeling as follows: For core demand, the forecasts are based on the forecast models used to produce SDG&E's 2005 Biennial Cost Allocation Proceeding, Application No. (A.) 03-09-031. These models were (1) updated with a more recent gas price forecast and economic assumptions and (2) extended to 2016 in order to determine the demand for that year. For noncore demand (EG and noncore, non-EG), the 2005 BCAP models were used to forecast demand for 2006 and the forecasting models used to produce the 2002 California Gas Report (CGR) were used to forecast demand for 2016. Both sets of models were updated with a more recent gas price forecast and economic assumptions.

[1] In answering this data request, please provide your assumptions in your forecasts as to electric generation plants retired, re-powered, or constructed in your utility's service territory.

RESPONSE 1 (continued)

It should be noted that the respondent gas utilities in R.04-01-025 will be preparing a more comprehensive long-term demand forecast later this year as part of the 2004 CGR.

It should also be noted that the Commission's current adopted peak-day criteria for service reliability is as follows: for firm noncore service, 1-in-10 cold year (i.e., all core demand and firm noncore demand is served); for core service, 1-in-35 cold year (i.e., all core demand is served and all noncore service is curtailed).

Table Q.1-EG indicates the assumptions used by SDG&E with regard to electric generating plants retired, re-powered, or constructed. This table reflects the assumptions for both SDG&E and SoCalGas.

Attachments:

- Table Q.1
- Table Q.1-EG

SDG&E Responses to CPUC Data Requests, R.04-01-025
Table Q.1 -- Total Demand

Please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016
Your Utility's demand forecasts for its service territory under the following scenarios.

	ANNUAL		ANNUAL/365		PEAK-DAY	
	2006	**2016**	**2006**	**2016**	**2006**	**2016**
TOTAL	MDTH	MDTH	MMCFD	MMCFD	MMCFD	MMCFD
	(a)	(b)	(c) = (a)/365	(d) = (b)/365	(e)	(f)
a. Average Year Scenarios						
i. Average Year	1,217,622	1,423,447	329	385	538	604
ii. Average Year + 10%	1,339,384	1,565,792	362	424	592	664
iii. Average Year + 20%	1,461,147	1,708,137	395	462	645	724
b. Abnormally Cold Year Scenarios						
i. 1 in 10 years	1,247,296	1,457,408	337	394	588	661
ii. 1 in 10 years + 10%	1,372,026	1,603,148	371	434	647	727
iii. 1 in 35 years	1,262,583	1,474,902	342	399	615	691
iv. 1 in 35 years + 10%	1,388,841	1,622,393	376	439	676	760
c. Abnormally Dry Year Scenarios						
i. 1 in 10 years	1,236,355	1,512,842	334	409	548	648
ii. 1 in 10 years + 10%	1,359,990	1,664,126	368	450	603	712
iii. 1 in 35 years	1,246,777	1,551,864	337	420	550	638
iv. 1 in 35 years + 10%	1,371,455	1,707,050	371	462	605	702
d. Abnormally Cold and Dry Year Scenarios						
i. 1 in 10 years	1,266,029	1,546,802	343	418	599	705
ii. 1 in 10 years + 10%	1,392,632	1,701,482	377	460	659	776
iii. 1 in 35 years	1,291,738	1,603,319	349	434	627	726
iv. 1 in 35 years + 10%	1,420,912	1,763,651	384	477	689	798

SDG&E Responses to CPUC Data Requests, R.04-01-025
Table Q.1 -- Core Demand

Please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016
Your Utility's demand forecasts for its service territory under the following scenarios.

	ANNUAL		ANNUAL/365		PEAK-DAY	
	2006	**2016**	**2006**	**2016**	**2006**	**2016**
CORE	MDTH	MDTH	MMCFD	MMCFD	MMCFD	MMCFD
	(a)	(b)	(c) = (a)/365	(d) = (b)/365	(e)	(f)
a. Average Year Scenarios						
i. Average Year	513,240	584,798	139	158	324	369
ii. Average Year + 10%	564,564	643,278	153	174	356	406
iii. Average Year + 20%	615,888	701,758	167	190	388	443
b. Abnormally Cold Year Scenarios						
i. 1 in 10 years	542,914	618,758	147	167	374	426
ii. 1 in 10 years + 10%	597,206	680,634	162	184	412	469
iii. 1 in 35 years	558,201	636,253	151	172	400	456
iv. 1 in 35 years + 10%	614,021	699,878	166	189	440	502
c. Abnormally Dry Year Scenarios						
i. 1 in 10 years	513,240	584,798	139	158	324	369
ii. 1 in 10 years + 10%	564,564	643,278	153	174	356	406
iii. 1 in 35 years	513,240	584,798	139	158	324	369
iv. 1 in 35 years + 10%	564,564	643,278	153	174	356	406
d. Abnormally Cold and Dry Year Scenarios						
i. 1 in 10 years	542,914	618,758	147	167	374	426
ii. 1 in 10 years + 10%	597,206	680,634	162	184	412	469
iii. 1 in 35 years	558,201	636,253	151	172	400	456
iv. 1 in 35 years + 10%	614,021	699,878	166	189	440	502

SDG&E Responses to CPUC Data Requests, R.04-01-025
Table Q.1 -- Noncore, Non-EG Demand

Please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016
Your Utility's demand forecasts for its service territory under the following scenarios.

	ANNUAL		ANNUAL/365		PEAK-DAY	
	2006	**2016**	**2006**	**2016**	**2006**	**2016**
NON-CORE, NON-EG	MDTH	MDTH	MMCFD	MMCFD	MMCFD	MMCFD
	(a)	(b)	(c) = (a)/365	(d) = (b)/365	(e)	(f)
a. Average Year Scenarios						
i. Average Year	245,588	256,319	66	69	74	77
ii. Average Year + 10%	270,146	281,951	73	76	82	85
iii. Average Year + 20%	294,705	307,583	80	83	89	93
b. Abnormally Cold Year Scenarios						
i. 1 in 10 years	245,588	256,319	66	69	74	77
ii. 1 in 10 years + 10%	270,146	281,951	73	76	82	85
iii. 1 in 35 years	245,588	256,319	66	69	74	77
iv. 1 in 35 years + 10%	270,146	281,951	73	76	82	85
c. Abnormally Dry Year Scenarios						
i. 1 in 10 years	245,588	256,319	66	69	74	77
ii. 1 in 10 years + 10%	270,146	281,951	73	76	82	85
iii. 1 in 35 years	245,588	256,319	66	69	74	77
iv. 1 in 35 years + 10%	270,146	281,951	73	76	82	85
d. Abnormally Cold and Dry Year Scenarios						
i. 1 in 10 years	245,588	256,319	66	69	74	77
ii. 1 in 10 years + 10%	270,146	281,951	73	76	82	85
iii. 1 in 35 years	245,588	256,319	66	69	74	77
iv. 1 in 35 years + 10%	270,146	281,951	73	76	82	85

SDG&E Responses to CPUC Data Requests, R.04-01-025
Table Q.1 -- EG Demand

Please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016
Your Utility's demand forecasts for its service territory under the following scenarios.

	ANNUAL		ANNUAL/365		PEAK-DAY	
	2006	**2016**	**2006**	**2016**	**2006**	**2016**
EG	MDTH	MDTH	MMCFD	MMCFD	MMCFD	MMCFD
	(a)	(b)	(c) = (a)/365	(d) = (b)/365	(e)	(f)
a. Average Year Scenarios						
i. Average Year	458,794	582,330	124	158	140	157
ii. Average Year + 10%	504,674	640,563	137	173	154	173
iii. Average Year + 20%	550,553	698,796	149	189	168	189
b. Abnormally Cold Year Scenarios						
i. 1 in 10 years	458,794	582,330	124	158	140	157
ii. 1 in 10 years + 10%	504,674	640,563	137	173	154	173
iii. 1 in 35 years	458,794	582,330	124	158	140	157
iv. 1 in 35 years + 10%	504,674	640,563	137	173	154	173
c. Abnormally Dry Year Scenarios						
i. 1 in 10 years	477,527	671,725	129	182	151	201
ii. 1 in 10 years + 10%	525,280	738,897	142	200	166	222
iii. 1 in 35 years	487,950	710,747	132	192	152	192
iv. 1 in 35 years + 10%	536,745	781,821	145	212	167	211
d. Abnormally Cold and Dry Year Scenarios						
i. 1 in 10 years	477,527	671,725	129	182	151	201
ii. 1 in 10 years + 10%	525,280	738,897	142	200	166	222
iii. 1 in 35 years	487,950	710,747	132	192	152	192
iv. 1 in 35 years + 10%	536,745	781,821	145	212	167	211

SDG&E Responses to CPUC Data Requests, R.04-01-025
Table Q.1-EG

State	Trans Area	Unit Name	Unit No	Max Rating	Fuel Name	Full Load HR	Installation Date
	Additions:	(expected after Jan 1, 2004)					
CA	CSCE	MtView	1	264.00	NG CA/AZ	7100	01/01/2006
CA	CSCE	MtView	2	264.00	NG CA/AZ	7100	01/01/2006
CA	CSCE	MtView	3	264.00	NG CA/AZ	7100	01/01/2006
CA	CSCE	MtView	4	264.00	NG CA/AZ	7100	01/01/2006
CA	CSCE	Generic	1	360.00	NG CA/AZ	7100	06/01/2012
CA	CSCE	Generic	2	360.00	NG CA/AZ	7100	06/01/2012
CA	CSCE	Generic	3	360.00	NG CA/AZ	7100	06/01/2012
CA	CSCE	Generic	4	260.00	NG CA/AZ	7100	01/01/2014
CA	CSCE	Generic	5	260.00	NG CA/AZ	7100	01/01/2014
CA	CSCE	Generic	6	360.00	NG CA/AZ	7100	12/31/2014
CA	CSCE	Generic	7	360.00	NG CA/AZ	7100	12/31/2014
CA	CSCE	Generic	8	360.00	NG CA/AZ	7100	12/31/2014
CA	CSDGE	Generic-Palomar	1	255.00	NG OtayMesa	7100	06/01/2006
CA	CSDGE	Generic-Palomar	2	255.00	NG OtayMesa	7100	06/01/2006
CA	CSDGE	Generic	3	250.00	NG Sempra	7100	06/01/2014
CA	CSDGE	Generic	4	250.00	NG Sempra	7100	06/01/2014
CA	LADWP	Haynes CC	3	250.00	NG Sempra	7100	07/01/2006
CA	LADWP	Haynes CC	4	250.00	NG Sempra	7100	07/01/2006
CA	LADWP	Generic	1	250.00	NG Sempra	7100	06/01/2012
	Retirements:						**Retirement Date**
CA	LADWP	Valley WSCC	3	160	NG Sempra		06/01/2003
CA	LADWP	Valley WSCC	4	160	NG Sempra		06/01/2003
CA	LADWP	Haynes	3	222	NG Sempra		01/01/2006
CA	LADWP	Haynes	4	222	NG Sempra		01/01/2006

QUESTION 2.a

For each of the scenarios in Question 1, a. (i-iii) through d. (i-iv) above please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below.

a. Intrastate pipeline capacity necessary to meet demand in service territory:

i. Total intrastate pipeline capacity necessary for service territory.
ii. Intrastate pipeline capacity necessary for core customers.
iii. Intrastate pipeline capacity necessary for noncore customers.

RESPONSE 2.a

2.a.i. Question 1, a. i-iii through d. i-iv request both annual average daily demand forecasts. SDG&E has also provided its peak-day demand forecasts. The annual average demand forecasts provided in SDG&E's Response 1 are not used in assessing the intrastate capacity of the SDG&E system to meet its customers' needs. The SDG&E system is a local transmission system that must be designed to meet the peak-day demand of its customers. This is because SDG&E does not have on-system storage. All demand must be met on the day it occurs so, as a result, only the peak day is relevant.

The majority of the peak day demand forecasts presented in 1.a.i-iii through 1.d.i-iv do not represent the SDG&E design conditions as approved by the Commission in its Decision No. (D.) 02-11-073. SDG&E designs its system to provide uninterrupted service to core customers only during a 1-in-35 year cold day event, and to both core and firm noncore customers during a 1-in-10 year cold day event. The peak-day demand forecasts that most represent SDG&E's design conditions are those provided for scenario 1.b.i. [1]

Table Q.2.a indicates the additional total intrastate capacity that might be needed for each of the hypothetical demand scenarios provided in Question 1.a.i-iii through 1.d.i-iv. These peak-day demand forecasts were compared to SDG&E's current transmission system sendout capacity of 655 MMcfd in the winter operating season.

SDG&E has not evaluated any of the scenarios presented in Response 1.a.i-iii through 1.d.i-iv in detail in order to identify the specific infrastructure improvements needed to meet the demand scenario. Such an analysis would be dependent upon the type, location, and seasonality of the incremental load. It would also depend on whether and to what extent deliveries were being received at Otay Mesa as discussed in response to Question 6.

However, in its Cost of Service Application, A.02-12-028, and its Biennial Cost Allocation Proceeding (BCAP) Application, A.03-09-031, SDG&E identified a contingency project that could expand the system capacity during the winter operating season if demand conditions warrant. These projects involve installing 24 miles of 36-inch diameter transmission pipeline from Rainbow Station to Escondido, which increases the system capacity by 50 MMcfd and is estimated to cost $64.9 million, and installing 26 miles of 36-inch diameter transmission pipeline from Escondido to Santee, which adds another 170 MMcfd of system capacity and is estimated to cost $69.9 million.

[1] The 1-in-35 year peak day forecasts provided for scenario b.iii do not represent SDG&E's design condition because service to both core and noncore customer classes are provided.

<u>RESPONSE 2</u> (continued)

2.a.ii Both core and noncore demand are included in all of SDG&E's demand forecasts prepared for in response to Question 1.a.i-iii through 1.d.i-iv. Any intrastate capacity additions identified in Response 2.a.i, above, for these hypothetical peak-day forecasts are required to meet the demand forecasts for both core and noncore customer classes. Individually, sufficient capacity exists to serve either customer class by itself. Intrastate capacity additions are only required when service to both customer classes is provided.

2.a.iii Please see Response 2.a.ii, above.

Attachment:

- Table Q.2.a

SDG&E Responses to CPUC Data Request, R.04-01-025
Table Q.2.a

Question 2.a For each of the scenarios in 1. a. i-iii through d. i-iv above please provide in aggregate amounts on an MMcfd basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below.

a. Intrastate pipeline capacity necessary to meet demand in service territory

i. Total intrastate pipeline capacity necessary for service territory

ii. Intrastate pipeline capacity necessary for core customers

iii. Intrastate pipeline capacity necessary for noncore customers

Response 2.a.i-iii

			PEAK-DAY - 655 MMcfd	
			2006	**2016**
TOTAL			MMCFD	MMCFD
a.	Average Year Scenarios			
	i.	Average Year	0	0
	ii.	Average Year + 10%	0	9
	iii.	Average Year + 20%	0	69
b.	Abnormally Cold Year Scenarios			
	i.	1 in 10 years	0	6
	ii.	1 in 10 years + 10%	0	72
	iii.	1 in 35 years	0	36
	iv.	1 in 35 years + 10%	21	105
c.	Abnormally Dry Year Scenarios			
	i.	1 in 10 years	0	0
	ii.	1 in 10 years + 10%	0	57
	iii.	1 in 35 years	0	0
	iv.	1 in 35 years + 10%	0	47
d.	Abnormally Cold and Dry Year Scenarios			
	i.	1 in 10 years	0	50
	ii.	1 in 10 years + 10%	4	121
	iii.	1 in 35 years	0	71
	iv.	1 in 35 years + 10%	34	143

QUESTION 2.b and 2.c

For each of the scenarios in Question 1, a. (i-iii) through d. (i-iv) above please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below.

b. Storage capacity necessary to meet demand:

i. Total storage capacity necessary for service territory.
ii. Storage capacity necessary for core customers.
iii. Storage capacity necessary for noncore customers.

c. Interstate pipeline capacity necessary to meet demand: [1]

i. Total interstate capacity necessary for service territory.
ii. Interstate pipeline capacity necessary for core customers.
Iii Interstate pipeline capacity necessary for noncore customers.

RESPONSE 2.b and 2.c

b. i-iii See Table Q.2.b.

c. I-iii See Table Q.2.c.

Attachment:

- Table Q.2.b
- Table Q.2.c

[1] "Interstate pipeline capacity" as used in this particular data request refers to firm transportation rights on interstate pipelines for Calendar Year 2006, but for Calendar Year 2016 more generally refers to access to out-of-state supplies of natural gas, whether transported on interstate pipelines to California or imported and shipped to Liquefied Natural Gas (LNG) facilities which access California's natural gas market.

Table Q.2.b
Total SDG&E Storage Capacity
for Years 2006 and 2016

Question 2.
For each of the scenarios in 1.a.i-iii through d.i-iv above, please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below

b. Storage capacity necessary to meet demand
i. Total storage capacity necessary for service territory

	STORAGE INVENTORY		STORAGE INJECTION		STORAGE WITHDRAWAL	
	SDG&E		SDG&E		SDG&E	
	2006	**2016**	**2006**	**2016**	**2006**	**2016**
TOTAL	MMCF	MMCF	MMCFD	MMCFD	MMCFD	MMCFD
a. Average Year Scenarios						
i. Average Year	7,722	8,847	36	42	185	211
ii. Average Year + 10%	8,494	9,732	40	46	204	232
iii. Average Year + 20%	9,266	10,617	43	50	222	253
b. Abnormally Cold Year Scenarios						
i. 1 in 10 years	8,971	10,279	41	48	228	259
ii. 1 in 10 years + 10%	9,868	11,307	45	53	250	285
iii. 1 in 35 years	8,971	10,279	41	48	250	284
iv. 1 in 35 years + 10%	9,868	11,307	45	53	275	313
c. Abnormally Dry Year Scenarios						
i. 1 in 10 years	7,722	8,847	36	42	185	211
ii. 1 in 10 years + 10%	8,494	9,732	40	46	204	232
iii. 1 in 35 years	7,722	8,847	36	42	185	211
iv. 1 in 35 years + 10%	8,494	9,732	40	46	204	232
d. Abnormally Cold and Dry Year Scenarios						
i. 1 in 10 years	8,971	10,279	41	48	228	259
ii. 1 in 10 years + 10%	9,868	11,307	45	53	250	285
iii. 1 in 35 years	8,971	10,279	41	48	250	284
iv. 1 in 35 years + 10%	9,868	11,307	45	53	275	313

* SDG&E is not able to project storage capacity requirements for its entire service territory since it is not aware of storage requirements for noncore transport-only customers.

Table Q.2.b
SDG&E Core Storage Capacity Projection
for Years 2006 & 2016

Question 2.
For each of the scenarios in 1.a.i-iii through d.i-iv above, please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below

b. Storage capacity necessary to meet demand
ii. Storage capacity necessary for core/core subscription customers

	STORAGE INVENTORY		STORAGE INJECTION		STORAGE WITHDRAWAL	
	SDG&E		SDG&E		SDG&E	
	2006	**2016**	**2006**	**2016**	**2006**	**2016**
CORE (with Core Subscription)	MMCF	MMCF	MMCFD	MMCFD	MMCFD	MMCFD
a. Average Year Scenarios						
i. Average Year	7,722	8,847	36	42	185	211
ii. Average Year + 10%	8,494	9,732	40	46	204	232
iii. Average Year + 20%	9,266	10,617	43	50	222	253
b. Abnormally Cold Year Scenarios						
i. 1 in 10 years	8,971	10,279	41	48	228	259
ii. 1 in 10 years + 10%	9,868	11,307	45	53	250	285
iii. 1 in 35 years	8,971	10,279	41	48	250	284
iv. 1 in 35 years + 10%	9,868	11,307	45	53	275	313
c. Abnormally Dry Year Scenarios						
i. 1 in 10 years	7,722	8,847	36	42	185	211
ii. 1 in 10 years + 10%	8,494	9,732	40	46	204	232
iii. 1 in 35 years	7,722	8,847	36	42	185	211
iv. 1 in 35 years + 10%	8,494	9,732	40	46	204	232
d. Abnormally Cold and Dry Year Scenarios						
i. 1 in 10 years	8,971	10,279	41	48	228	259
ii. 1 in 10 years + 10%	9,868	11,307	45	53	250	285
iii. 1 in 35 years	8,971	10,279	41	48	250	284
iv. 1 in 35 years + 10%	9,868	11,307	45	53	275	313

* SDG&E Storage Inventory & Injection for Average/day Demand

NORMAL-YEAR	**7,722**	**8,847**	**36**	**42**
COLD-YEAR	**8,971**	**10,279**	**41**	**48**

* SDG&E Storage Withdrawal equals Peak Day Demand minus Interstate Capacity

* SDG&E filed in its 2005 BCAP Application 03-09-031 for storage capacity necessary for its core customer requirements, based upon its proportional average core demand to SoCalGas:

Inventory:	10,150	MDth	10,030	MMcf
Injection:	47.5	MDth/day	46.9	MMcf/day
Withdrawal:	280.5	MDth/day	277.2	MMcf/day
Assumed Heating Value	1.012	Dth/Mcf	**NOT INCLUDED IN RESPONSE**	

Table Q.2.b
SDG&E Noncore Storage Capacity Projection
for Years 2006 & 2016

Question 2.
For each of the scenarios in 1.a.i-iii through d.i-iv above, please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below

b. Storage capacity necessary to meet demand
iii. Storage capacity necessary for noncore customers (which are not core subscription customers)

	STORAGE INVENTORY		STORAGE INJECTION		STORAGE WITHDRAWAL	
	SDG&E		SDG&E		SDG&E	
	2006	**2016**	**2006**	**2016**	**2006**	**2016**
NONCORE (w/o Core Sub)	MMCF	MMCF	MMCFD	MMCFD	MMCFD	MMCFD
a. Average Year Scenarios						
i. Average Year	0	0	0	0	0	0
ii. Average Year + 10%	0	0	0	0	0	0
iii. Average Year + 20%	0	0	0	0	0	0
b. Abnormally Cold Year Scenarios						
i. 1 in 10 years	0	0	0	0	0	0
ii. 1 in 10 years + 10%	0	0	0	0	0	0
iii. 1 in 35 years	0	0	0	0	0	0
iv. 1 in 35 years + 10%	0	0	0	0	0	0
c. Abnormally Dry Year Scenarios						
i. 1 in 10 years	0	0	0	0	0	0
ii. 1 in 10 years + 10%	0	0	0	0	0	0
iii. 1 in 35 years	0	0	0	0	0	0
iv. 1 in 35 years + 10%	0	0	0	0	0	0
d. Abnormally Cold and Dry Year Scenarios						
i. 1 in 10 years	0	0	0	0	0	0
ii. 1 in 10 years + 10%	0	0	0	0	0	0
iii. 1 in 35 years	0	0	0	0	0	0
iv. 1 in 35 years + 10%	0	0	0	0	0	0
* SDG&E assumption for Noncore Storage Capacity						
All Scenarios	**0**	**0**	**0**	**0**	**0**	**0**

* SDG&E is responsible only for obtaining storage capacity for its bundled utility-procurement core customers by contract with SoCalGas. SDG&E assumes no storage requirements for noncore self-procurement transport-only gas customers in its service territory.

Table Q.2.c.
SDG&E Total Interstate Pipeline Capacity Projection
for Years 2006 & 2016

Question 2.

For each of the scenarios in 1.a.i-iii through d.i-iv above, please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below

c. Interstate pipeline capacity necessary to meet demand

i. Total interstate pipeline capacity necessary for service territory

	SDG&E	
	2006	**2016**
TOTAL	Avg. MMCFD	Avg. MMCFD
a. Average Year Scenarios		
i. Average Year	329	385
ii. Average Year + 10%	362	424
iii. Average Year + 20%	395	462
b. Abnormally Cold Year Scenarios		
i. 1 in 10 years	337	394
ii. 1 in 10 years + 10%	371	434
iii. 1 in 35 years	342	399
iv. 1 in 35 years + 10%	376	439
c. Abnormally Dry Year Scenarios		
i. 1 in 10 years	334	409
ii. 1 in 10 years + 10%	368	450
iii. 1 in 35 years	337	420
iv. 1 in 35 years + 10%	371	462
d. Abnormally Cold and Dry Year Scenarios		
i. 1 in 10 years	343	418
ii. 1 in 10 years + 10%	377	460
iii. 1 in 35 years	349	434
iv. 1 in 35 years + 10%	384	477

Table Q.2.c.
SDG&E Core Interstate Pipeline Capacity Projection
for Years 2006 & 2016

Question 2.

For each of the scenarios in 1.a.i-iii through d.i-iv above, please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below

c. Interstate pipeline capacity necessary to meet demand

ii. Interstate pipeline capacity necessary for core/core subscription customers

	SDG&E	
	2006	**2016**
CORE (with Core Subscription)	Avg. MMCFD	Avg. MMCFD
a. Average Year Scenarios		
i. Average Year	141	160
ii. Average Year + 10%	155	176
iii. Average Year + 20%	169	192
b. Abnormally Cold Year Scenarios		
i. 1 in 10 years	149	170
ii. 1 in 10 years + 10%	164	187
iii. 1 in 35 years	153	174
iv. 1 in 35 years + 10%	168	192
c. Abnormally Dry Year Scenarios		
i. 1 in 10 years	141	160
ii. 1 in 10 years + 10%	155	176
iii. 1 in 35 years	141	160
iv. 1 in 35 years + 10%	155	176
d. Abnormally Cold and Dry Year Scenarios		
i. 1 in 10 years	149	170
ii. 1 in 10 years + 10%	164	187
iii. 1 in 35 years	153	174
iv. 1 in 35 years + 10%	168	192
* SDG&E Demand for **Core & Core Subscription**		
Average Year	141	160
1 in 10 years	149	170
1 in 35 years	153	174
* Range of Interstate capacity for **Core & Core Subscription**		
80% of Average Demand	113	128
120% of Average Demand	169	192

Table Q.2.c.
SDG&E Noncore Interstate Pipeline Capacity Projection
for Years 2006 & 2016

Question 2.

For each of the scenarios in 1.a.i-iii through d.i-iv above, please provide in aggregate amounts on an MMcf/d basis for Calendar Years 2006 and 2016 the infrastructure needed for Your Utility's forecasts identified below

c. Interstate pipeline capacity necessary to meet demand

iii. Interstate pipeline capacity necessary for noncore customers (which are not core subscription customers)

	SDG&E	
	2006	**2016**
NONCORE (w/o Core Sub)	Avg. MMCFD	Avg. MMCFD
a. Average Year Scenarios		
i. Average Year	188	225
ii. Average Year + 10%	207	247
iii. Average Year + 20%	226	270
b. Abnormally Cold Year Scenarios		
i. 1 in 10 years	188	225
ii. 1 in 10 years + 10%	207	247
iii. 1 in 35 years	188	225
iv. 1 in 35 years + 10%	207	247
c. Abnormally Dry Year Scenarios		
i. 1 in 10 years	194	249
ii. 1 in 10 years + 10%	213	274
iii. 1 in 35 years	196	259
iv. 1 in 35 years + 10%	216	285
d. Abnormally Cold and Dry Year Scenarios		
i. 1 in 10 years	194	249
ii. 1 in 10 years + 10%	213	274
iii. 1 in 35 years	196	259
iv. 1 in 35 years + 10%	216	285

* SDG&E Noncore Interstate Capacity equal to Noncore demand

QUESTION 3

Please provide information concerning the firm interstate pipeline transportation contracts (with California primary delivery points) held by California Natural Gas Public Utilities and by Other Entities [1]

a. Provide the amount of firm transportation rights Your Utility currently has on each interstate pipeline to California.

b. Provide the total amount of firm interstate pipeline transportation rights currently held by Other Entities (with primary delivery points to California) on each of the following interstate pipelines:

   i. El Paso Natural Gas Company
   ii. Transwestern Pipeline Company
   iii. Gas Transmission Northwest Corporation
   iv. Kern River Gas Transmission Company (Kern River)

c. Provide the total amount of firm interstate pipeline transportation rights held by California Natural Gas Public Utilities or Other Entities which had primary delivery points to California in Calendar Year 2000 but now have primary delivery points to markets other than California due to long-term capacity releases on each of the following interstate pipelines: [2]

   i. El Paso Natural Gas Company
   ii. Transwestern Pipeline Company
   iii. Gas Transmission Northwest Corporation
   iv. Kern River

d. Provide the total amount of firm interstate pipeline transportation rights which will be held by Other Entities (with primary delivery points to California) on each of the following interstate pipelines in Calendar Years 2005, 2006 and 2007. [3]

   i. El Paso Natural Gas Company
   ii. Transwestern Pipeline Company
   iii. Gas Transmission Northwest Corporation
   iv. Kern River

e. Please provide a general description of any contingency plan Your Utility currently has in place to the extent that Other Entities do not subscribe to a sufficient amount of firm interstate pipeline transportation rights to California in order to serve the noncore market in Calendar Years 2005, 2006 and 2007.

---

[1] The phrase "Other Entities" as used in this data request refers to participants in the noncore market in California, whether end-users (e.g., generators or industrial customers) or marketers which sell natural gas to end-users in California. Southwest Gas only needs to identify for its response to this data request the firm transportation rights Your Utility has on interstate pipelines to serve its California customers, and a breakdown of its core customers and noncore customers' demand (by volumes and percentages).

[2] If Your Utility is unable to answer some or all of this particular data request, please provide partial answers where you can and explain why you are unable to provide fuller requests.

[3] If Your Utility is unable to answer some or all of this particular data request, please provide partial answers where you can and explain why you are unable to provide fuller responses.

RESPONSE 3

a. - d. See Table Q.4 provided in response to Question 4.a. This table indicates the current interstate pipeline capacity contracts held by SDG&E.

Information regarding pipeline contracts held by Other Entities is provided in the Response of SoCalGas to Question 3 and is not restated here.

e. SDG&E does not have any contingency plans in place to the extent that Other Entities do not subscribe to a sufficient amount of firm interstate pipeline transportation rights to California in order to serve the noncore market. SDG&E does not believe it is appropriate for it to hold firm interstate pipeline capacity to meet the needs of its noncore customers.

QUESTION 4

Please provide the deadlines facing each of the California Natural Gas Public Utilities and others identified below:

a. For each contract which Your Utility currently has with interstate pipelines for firm transportation rights to California primary delivery points (identified by pipeline & Contract Demand amount, and pipeline delivery points) provide:

   i. Date of expiration of contract.

   ii. Notice of termination date or exercise of first refusal date.

b. Provide any current interstate pipeline's open season deadline for expansions to California.

c. Provide LNG-related deadlines for access in Baja California.

d. Provide any other deadlines affecting long-term supply options.

RESPONSE 4

a. Table Q.4 provides the requested information regarding SDG&E's current firm transportation rights on the El Paso and the Canadian path between Canada and the SoCalGas system.

b. On February 4, 2004 El Paso Natural Gas Company announced an open season which will end on March 4, 2004, to allow parties to submit bids for transportation service involving Line 1903, capacity on Mojave, and EPNG's existing pipeline system. Line 1903 refers to the portion of the All American Pipeline which lies within California. This open season contemplates moving gas from Topock or Daggett to Ehrenberg or East of California (EOC) markets either under extensions of existing contracts or through new contracts with EPNG.

c. SDG&E is only aware of the deadline referenced by the Commission in its OIR: "There is currently an open season deadline of September 1, 2004 for use of pipelines in Mexico and the United States for this natural gas to be transported to Arizona and other East of California locations." (p.14)

d. SDG&E is not aware of any other deadlines affecting long-term supply options at this time.

Attachment:

- Table Q.4

SDG&E Responses to CPUC Data Requests (R.04-01-025)
Table Q.4

Pipeline	Acquired Agreement Code	Capacity Mcf/Day	Capacity MMBtu/Day	Term Beginning Date	Term End Date	Termination Notice Date	ROFR Date	Primary Delivery Point(s)
Southwest								
El Paso Natural Gas Company	9844	10,000	10,230	11/11/1991	02/28/2007	02/28/2006		SoCal Ehrenberg
El Paso Natural Gas Company	9MDF	3,607	3,690	06/01/2001	05/31/2006	05/31/2005	12/02/2005	SoCal Ehrenberg
El Paso Natural Gas Company	9NKE	12,230	12,512	11/01/2002	12/31/2004	12/31/2003	No ROFR	SoCal Topock
Canadian Path								
Trans-Canada Nova Gas Transmission Ltd.	----	3,408	3,454	11/01/2002	10/31/2008	10/31/2007	N/A	Alberta/BC Border
Trans-Canada Nova Gas Transmission Ltd.	----	21,888	22,185	08/01/2003	10/31/2008	10/31/2007	N/A	Alberta/BC Border
Trans-Canada Nova Gas Transmission Ltd.	----	4,979	5,047	11/01/2003	10/31/2012	10/31/2011	N/A	Alberta/BC Border
Trans-Canada Nova Gas Transmission Ltd.	----	5,968	6,049	11/01/2003	10/31/2013	10/31/2012	N/A	Alberta/BC Border
Trans-Canada Nova Gas Transmission Ltd.	----	17,375	17,611	12/01/2003	10/31/2005	10/31/2004	N/A	Alberta/BC Border
Trans-Canada Pipeline Limited - B.C. System	----	53,105	53,826	11/01/1993	10/31/2008	10/31/2007	N/A	US Border/Kingsgate, BC
Gas Transmission Northwest Corporation (GTN)	SDGE	51,804	52,508	11/01/1993	10/31/2023			Malin, Oregon
Pacific Gas & Electric Company (PG&E)	00172	51,236	51,932	11/01/1993	10/31/2023			SoCal Wheeler Ridge
SoCalGas Wheeler Ridge Compressor Sta.	0900	51,236	51,932	11/01/1993	10/31/2006			SoCalGas pipeline system

QUESTION 5

Provide the following information concerning increasing access to Kern River: [1]

a. Locations where intrastate pipelines currently interconnect with Kern River and their current interconnection capacity.

b. Estimate of costs of expansions at each interconnection at different amounts of capacity expansions (e.g., 100 MMcf/d, 200 MMcf/d).

c. Amount of Kern River capacity available throughout the year to California Natural Gas Public Utilities. [2]

RESPONSE 5

This question is not applicable to the SDG&E system. A response is provided by SoCalGas as these questions relate to its system, or an integrated SoCalGas/SDG&E transmission system.

[1] PG&E and SoCalGas are the only utilities which need to respond to this request.

[2] Assume for this data request that capacity under contracts with Nevada companies and capacity under contracts to direct connection customers are not available throughout the year to the California Natural Gas Public Utilities.

QUESTION 6

Please provide the range of new supply access costs for proposed LNG facilities at Otay Mesa, Long Beach and Oxnard that represent the best estimate of Your Utility. [1]

RESPONSE 6

The costs discussed below are the best estimates available at this point in time given the large number of potential combinations and permutations of options. SDG&E's and SoCalGas current systems are depicted in Map Q.6.1 and Q.6.2, respectively.

The magnitude of intrastate facility costs depends largely upon the interconnect location of the new or expanded supply source, the size of the new or expanded source, and whether the source is allowed to displace existing supply sources such that the total 3,875 MMcf/d firm receipt point and redelivery capacity remains the same, or whether the new or expanded interconnect location is allowed to increase the firm receipt point and redelivery capacity of the entire system.

The costs set forth below are factored estimates (generally +/- 30%) based on recent like projects in similar areas. They do not represent detailed construction estimates. The estimates do not include the costs of facilities necessary to reach the SoCalGas/SDG&E systems. Costs assume that the delivery pressure is sufficient to enter the SoCalGas/SDG&E systems. Finally, the cost estimates assume that each project was built on an individual basis; that is, only the project in question is being added to the SoCalGas/SDG&E system. If multiple projects are built at once or sequentially, costs are not necessarily the sum of the individual projects but are likely to require facilities in addition to those included in these cost estimates. This effect is discussed below in more detail.

In R.04-01-025, the Commission directed SoCalGas and SDG&E to address the costs of capacity expansion for interconnecting facilities and intrastate pipelines to facilitate LNG supply availability to California at Otay Mesa or at any receipt point in or near the utilities' service territory (i.e., onshore or offshore California).

SoCalGas and SDG&E have examined three locations on the SoCalGas/SDG&E transmission system for the receipt of LNG supplies. These sites are:

- Otay Mesa meter station on the SDG&E system near the U.S./Mexico border;
- Salt Works Station on the SoCalGas system near Long Beach; and
- Center Road Station on the SoCalGas system near Oxnard.

Each of these potential locations was evaluated at several levels of new supply, and system improvements were identified based on both a "displacement" and an "expansion" basis. On a displacement basis, new supplies would compete for existing pipeline delivery capacity and potentially displace current supplies, i.e. the SoCalGas system firm receipt and redelivery capacity would remain 3,875 MMcf/d. On an expansion basis, the SoCalGas system firm receipt and redelivery capacity would be expanded beyond 3,875 MMcf/d to accommodate the new supply without displacing the receipt of current supplies. Each potential receipt point is discussed in detail below.

---

[1] This request applies to SoCalGas and SDG&E only. It can be the presentation by David G. Taylor on December 10, 2003 at the CPUC-CEC workshop (Panel II D-LNG Facilities) or updated information in the same format and methodology as used in that presentation.

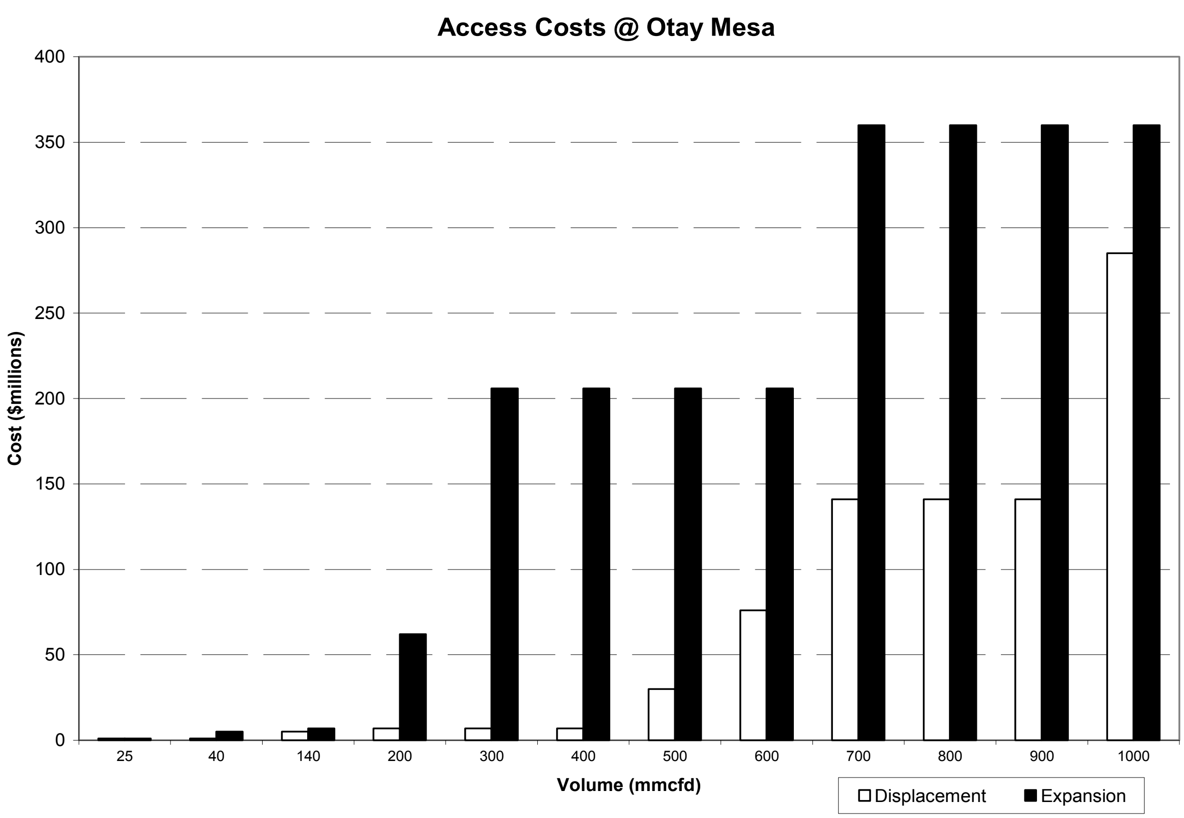
RESPONSE 6 (continued)

Otay Mesa

The SDG&E gas transmission system terminates at the Otay Mesa meter station near the U.S./Mexico border. The current SDG&E transmission system is indicated in Map Q.6.1. The SDG&E transmission system was originally designed and constructed to receive gas supplies in the north from SoCalGas and move those supplies to load centers in the south.

With system improvements on the SoCalGas/SDG&E system, including at the Otay Mesa meter station, gas supplies could be received at Otay Mesa and moved north for use by SDG&E or SoCalGas customers from a Mexican pipeline, such as the Transportadora de Gas Natural (TGN) pipeline. Supplies in excess of the local San Diego demand would need to be redelivered into the SoCalGas system at Rainbow Station. Figure Q.6.1 and Table Q.6.1 below present the preliminary cost estimates for the facilities necessary to accept and redeliver supplies at Otay Mesa for several assumed levels of delivered supply.

Figure Q.6.1



RESPONSE 6 (continued)

Table Q.6.1

Access Costs Detail, Otay Mesa

Facility Improvement	Cost $MM	Delivered volume (MMCF/D)											
		25	40	140	200	300	400	500	600	700	800	900	1000
Reverse existing meter at Otay Mesa	1	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Minor improvements to SDG&E system	4		●	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Modify Moreno compressor station	2			●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Santee-Miramar pipeline	23							○					
Santee-Escondido pipeline	69					●	●	●	○●	○●	○●	○●	○●
Escondido-Rainbow pipeline	65									○●	○●	○●	○●
Border-Santee pipeline	89									●	●	●	○●
Moreno-Chino looping on SoCalGas system	55				●	●	●	●	●	●	●	●	○●
Moreno-Prado looping on SoCalGas system	75					●	●	●	●	●	●	●	●

○ Displacement basis
● Expansion basis

A basic set of facility improvements is required on the SDG&E system to reverse the flow of gas in the SDG&E system and accept any significant volume of supply delivered at Otay Mesa. These improvements include changes to the piping and valving at the Otay Mesa meter station to "reverse" the station and flow gas from the south to the north; minor improvements on the SDG&E system such as the removal of check valves and the construction of new pressure limiting stations; and for all but a nominal level of supply delivered at Otay Mesa, modifications to SDG&E's Moreno compressor station to enable it to compress gas supply from the SDG&E system so that it can enter the SoCalGas system. [2] This is required because any supply delivered into the SDG&E system in excess of the SDG&E system demand must be redelivered into the SoCalGas system. SoCalGas and SDG&E have estimated the minimum level of demand on the SDG&E system to be approximately 140 MMcf/d.

Improvements to the SDG&E/SoCalGas system beyond this basic set are determined by the level of supply delivered at Otay Mesa and whether or not that supply expands SoCalGas' system receipt and redelivery capacity of 3,875 MMcf/d. Volumes received at Otay Mesa would be delivered ultimately into a single 36-inch diameter pipeline that runs from the Otay Mesa meter station to Santee. At Santee, the 36-inch diameter pipeline interconnects with a 20-inch diameter pipeline, which supplies SDG&E's 30- and 16-inch diameter transmission mains running south from Rainbow Station. As the volumes delivered at Otay Mesa increase, the 20-inch diameter pipeline becomes a constraint to transporting supply to the SDG&E load centers and for redelivery to SoCalGas, requiring looping on the SDG&E system.

[2] All improvements except the modification to the Moreno compressor station are currently underway. These projects were presented as Project Number 2466, Pressure Betterment – Otay Mesa Meter Station in A.02-12-028 and SDG&E agreed to proceed with Project Number 2466 as part of a settlement agreement.

RESPONSE 6 (continued)

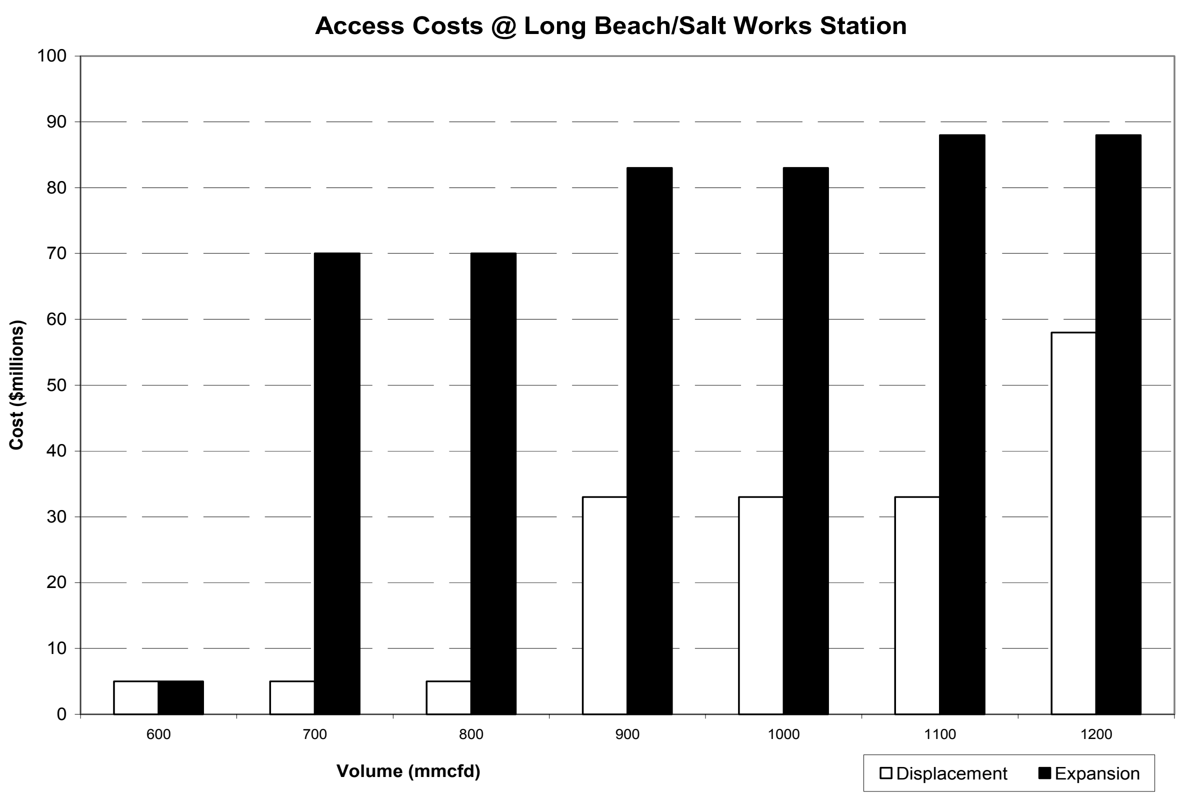
On the SoCalGas system, the capacity west of Moreno Station is 760 MMcf/d. Therefore, at the highest volumes delivered at Otay Mesa (or for all but nominal volumes delivered at Otay Mesa on an expansion basis), looping on the SoCalGas system west of Moreno Station is also required.

Delivery pressure requirements at Otay Mesa range from 700 to 800 psig, depending upon the volume delivered.

Salt Works Station – Long Beach

SoCalGas' transmission Line 765 terminates at Salt Works Station near the Long Beach/L.A. Harbor area. Line 765 is a relatively new 30-inch diameter pipeline that runs in a north/south direction across the Los Angeles basin. Most of the transmission pipelines in the Los Angeles basin have a Maximum Allowable Operating Pressure (MAOP) of 465 psig. Line 765, however, has an MAOP of 650 psig. This large diameter pipeline with a higher MAOP and close proximity to the L.A. Harbor is an ideal receipt point for new supplies delivered into the Los Angeles basin. Figure Q.6.2 and Table Q.6.2 below present the preliminary cost estimates for accepting supplies at Salt Works Station at various assumed volume levels on both a displacement and expansion basis. These cost estimates only include costs necessary to improve the SoCalGas system; they do not include any costs upstream of the receipt point, such as pipeline between the supplier (such as an LNG plant) and Salt Works Station or compression to meet delivery pressure requirements.

Figure Q.6.2



RESPONSE 6 **(continued)**

Table Q.6.2

Access Costs Detail, Long Beach

Facility Improvement	Cost $MM	Delivered volume (MMCF/D) 600	700	800	900	1000	1100	1200
Improvements at Salt Works Station	5	○●	○●	○●	○●	○●	○●	○●
Partially loop Line 765	13		●	●	○●	○●	○●	○●
Rebuild existing pressure limiting stations	2		●	●	○●	○●	○●	○●
New compressor station at Quigley	20 - 50		●	●	●	●	●	○●
New compressor station at Brea	13				○●	○●	○●	○●
Modify Moreno compressor station	2						●	○●
New compressor station at Shaver Summit	3						●	○●

○ Displacement basis
● Expansion basis

Approximately 60% of the entire SoCalGas system demand and nearly all of the southern California electric generation demand is located in the Los Angeles basin. This high concentration of demand allows for relatively large volumes of supply to be accepted at Salt Works Station without significant facility investment, particularly on a displacement basis. However, under low demand conditions when the supply delivered at Salt Works Station exceeds the Los Angeles basin demand, the excess supply has no access to load centers outside of the Los Angeles basin because the piping in the Los Angeles basin operates at a lower pressure than the remainder of the SoCalGas transmission system. New compression therefore would be required to transport the excess supply out of the Los Angeles basin, into one of SoCalGas' high pressure transmission pipelines, and redeliver the gas to other SoCalGas or SDG&E load centers.

SoCalGas has identified locations at two of its "city gates" where new compression could be sited – a 25,000 HP compressor station at Quigley Station [3] in the north of the Los Angeles basin and an 8,000 HP compressor station at Brea Station in the east. Gas compressed out of the Los Angeles basin at Quigley Station could be used to meet customer demand in the San Joaquin Valley, in the Ventura/Oxnard area, and in the Inland Empire and High Desert communities. A compressor station at Brea Station can be used to redeliver the excess Los Angeles basin supply to communities in Riverside and San Diego counties. By adding a smaller 850 HP compressor station at Shaver Summit, this excess supply could even serve communities in the Imperial Valley. Note, however, that compressors at Brea and Shaver Summit, as well as modifications to the Moreno compressor station so that gas can flow east, are only necessary for the higher volumes assumed to be delivered at Salt Works Station.

As noted above, SoCalGas' pipeline system at Salt Works Station has an MAOP of 650 psig. Therefore, new suppliers must be able to deliver at pressures up to this MAOP at Salt Works Station.

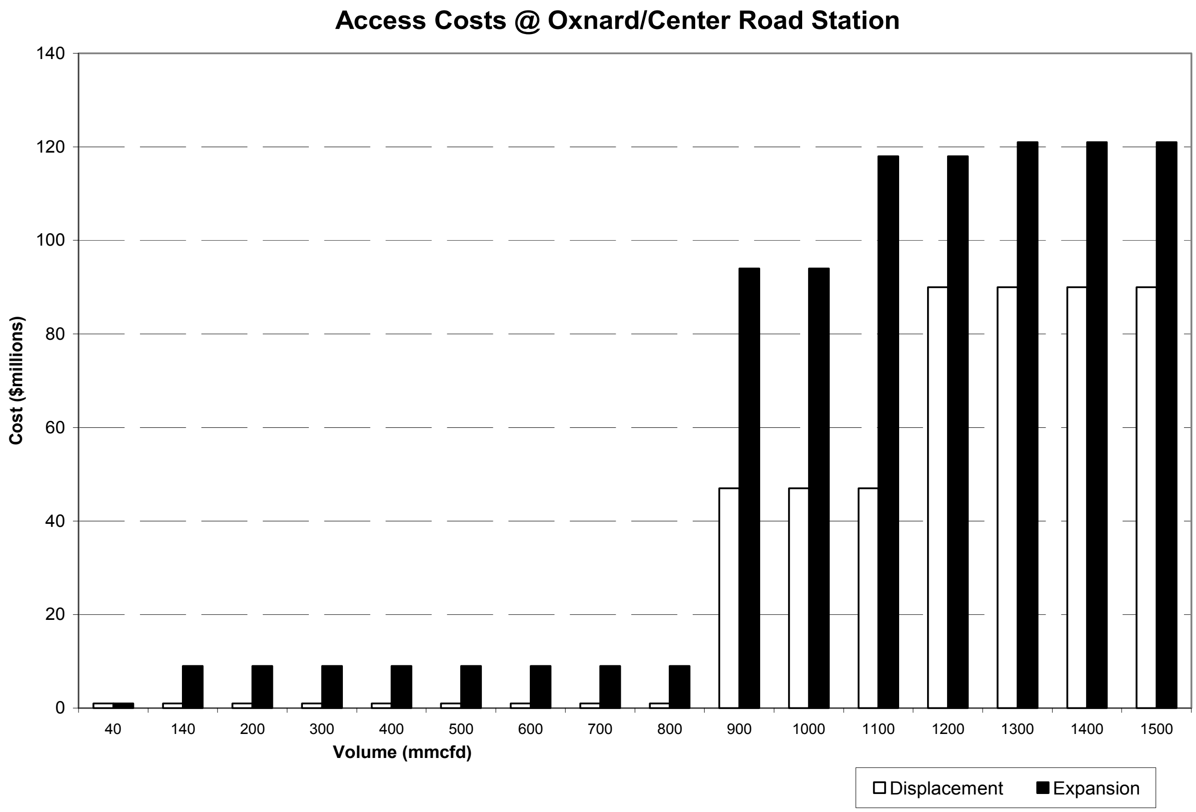
[3] 10,000 HP under the displacement scenario.

RESPONSE 6 (continued)

Center Road Station – Oxnard

Figure Q.6.3 and Table Q.6.3 below present the preliminary cost estimates for accepting supplies at Center Road Station for varying assumed volumes of delivered supply on both a displacement and expansion basis. As in the case with a receipt point at Otay Mesa or Salt Works Station, these cost estimates do not include any costs upstream of the receipt point.

Figure Q.6.3



RESPONSE 6 (continued)

Table Q.6.3

Access Costs Detail, Oxnard

Facility Improvement	Cost $MM	Delivered volume (MMCF/D) 40	140	200	300	400	500	600	700	800	900
Improvements at Center Road Station	1	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Loop Line 225, Saugus to Quigley	8 - 10		●	●	●	●	●	●	●	●	●
Loop Line 324	40 - 60										○●
Rebuild existing PLS/crossovers	6										○●
Loop Line 225, Honor to Saugus	3										●
Extend Line 3008	6 - 10										●
New compression at Brea (10,000 HP)	25										●
New compression at Shaver (300 HP)	1										●
Modify Moreno compressor station	2										●

○ Displacement basis
● Expansion basis

Facility Improvement	Cost $MM	Delivered volume (MMCF/D) 1000	1100	1200	1300	1400	1500
Improvements at Center Road Station	1	○●	○●	○●	○●	○●	○●
Loop Line 225, Saugus to Quigley	8 - 10	●	●	○●	○●	○●	○●
Loop Line 324	40 - 60	○●	○●	○●	○●	○●	○●
Rebuild existing PLS/crossovers	6	○●	○●	○●	○●	○●	○●
Loop Line 225, Honor to Saugus	3	●	●	○●	○●	○●	○●
Extend Line 3008	6 - 10	●	●	○●	○●	○●	○●
New compression at Brea (10,000 HP)	25	●	●	●	●	●	●
New compression at Shaver (300 HP)	1	●	●	●	●	●	●
Modify Moreno compressor station	2	●	●	●	●	●	●
New compression at Wheeler Ridge (1,000 HP)	3				●	●	●

○ Displacement basis
● Expansion basis

RESPONSE 6 (continued)

SoCalGas' Center Road Station in Oxnard interconnects transmission Lines 324, 404, and 406. This feature makes Center Road Station a logical point to receive new supplies delivered in the Oxnard/Ventura area. Supplies delivered at Center Road Station would have access to load centers in Ventura and Santa Barbara Counties, and communities north of Gaviota along the California coast.

With improvement to the SoCalGas system, supply in excess of the local Coastal System demand (minimum local demand estimated to be 50 MMcf/d) can be redelivered to the Los Angeles basin load centers via Lines 404 and 406, or transported to Line 225 via Line 324 and redelivered to load centers in the San Joaquin Valley, Inland Empire, and High Desert communities.

Receipts at Center Road Station must be able to meet the MAOP of the SoCalGas transmission system, which is approximately 800 psig at this location. If a new pipeline is required in order to deliver supplies to Center Road Station, delivered pressure into that pipeline by the supplier may need to be significantly greater than 800 psig in order to meet this pressure requirement at Center Road Station. The level of delivered pressure into this new pipeline would be a function of the distance from the supplier to Center Road Station, the diameter of the new pipeline, and the volume of supply transported to Center Road Station.

It should be noted that the "displacement" and "expansion" cases are not mutually exclusive at all assumed volume levels. Some of the facility improvements necessary to accept and redeliver supplies on a displacement basis also have the effect of increasing SoCalGas' overall system receipt and redelivery capacity of 3,875 MMcf/d as the figures and tables shown above demonstrate.

For example, it would not cost significantly more to accept 140 MMcf/d at Otay Mesa on an expansion basis than a displacement basis. At Salt Works Station, it costs the same to accept and redeliver 600 MMcf/d on either a displacement or expansion basis. At Center Road Station, it costs the same to increase the receipt point and redelivery capacity by 40 MMcf/d on either a displacement or expansion basis, but it also should be noted that SoCalGas' total system receipt and redelivery capacity can be increased by 800 MMcf/d by adding facilities costing less than $20 million to accept supplies at Salt Works Station as depicted in Figure Q.6.3 and Table Q.6.3 above. Of course, at higher volumes at each of these receipt points, the cost of facilities necessary to increase the system receipt and redelivery capacity is much greater than the cost of facilities necessary to accept and redeliver volumes that would displace supplies from existing receipt points.

Multiple LNG Receipt Points

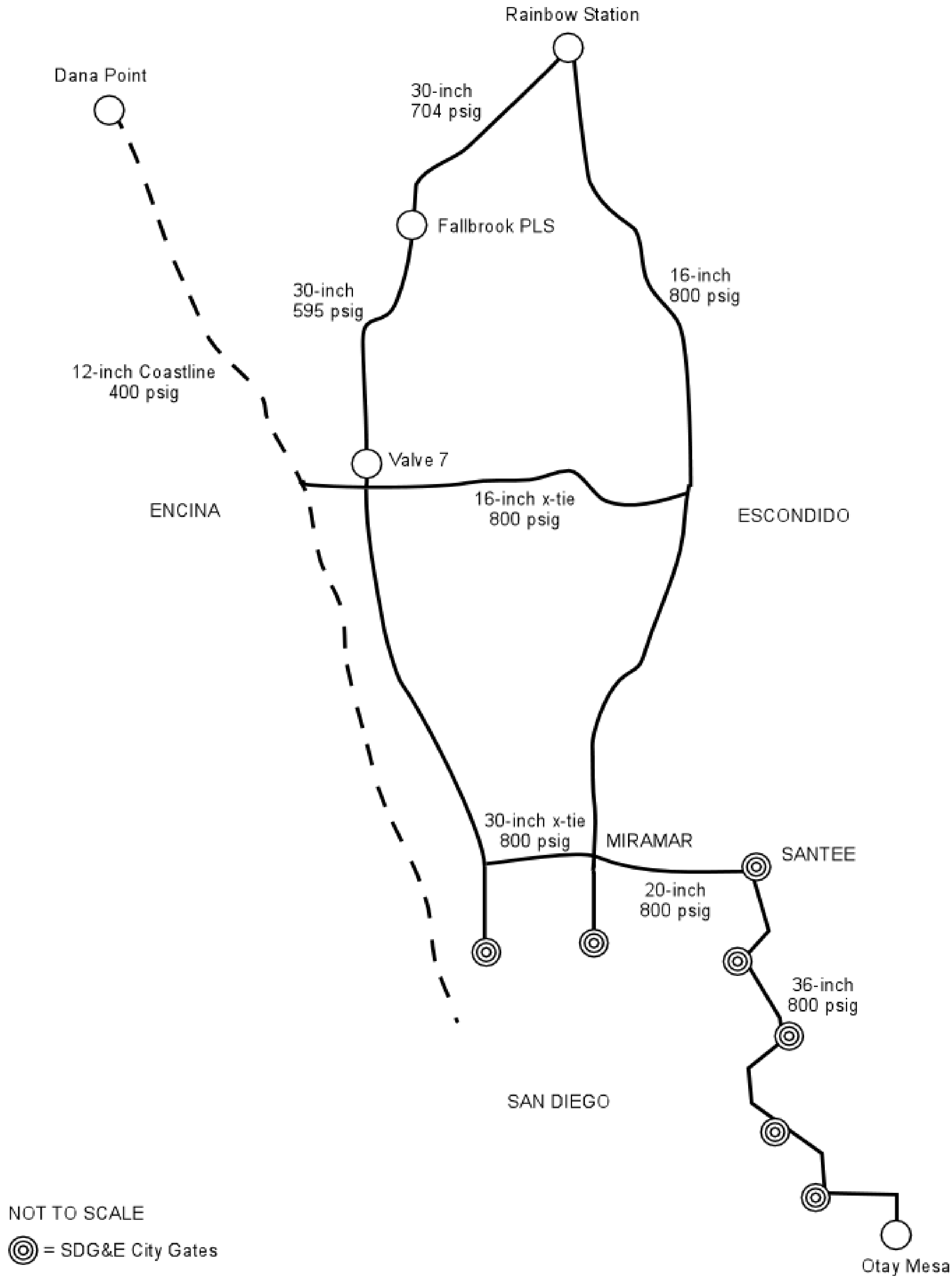
SoCalGas and SDG&E have also examined the system improvements necessary to establish two receipt points simultaneously for LNG on the SoCalGas/SDG&E transmission system. For this assessment, SoCalGas examined potential volumes delivered at Otay Mesa, Salt Works Station, and Center Road Station. The scenarios examined were (1) 600 MMcf/d delivered at Otay Mesa and 800 MMcf/d delivered at Center Road Station; and (2) 600 MMcf/d delivered at Otay Mesa and 800 MMcf/d delivered at Salt Works Station. Of course, many other scenarios are possible, but SoCalGas has not attempted to examine every possible combination. These cost figures are intended to illustrate how facility costs do or do not increase if significant volumes are received at multiple receipt points.

RESPONSE 6 (continued)

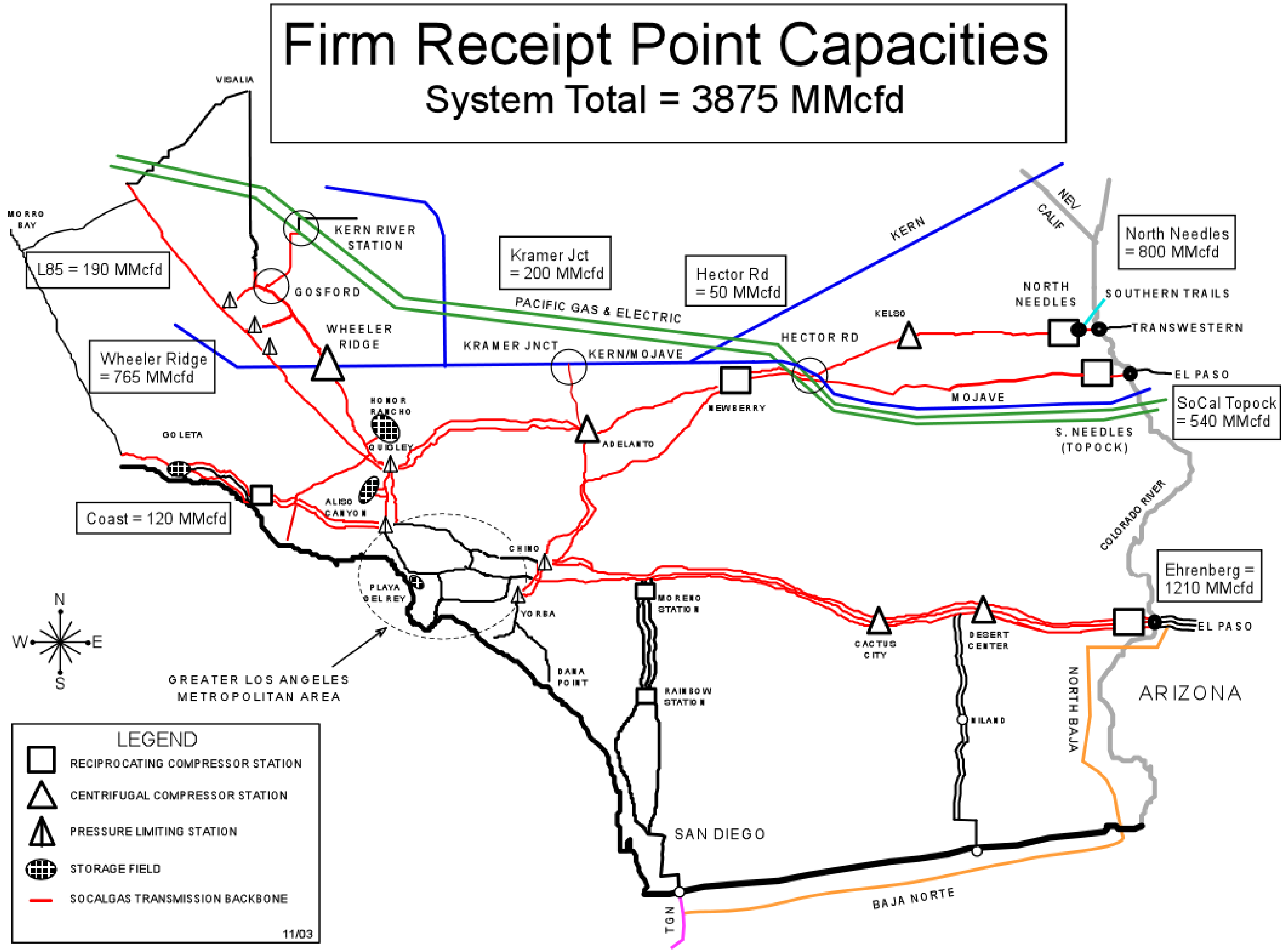
For the Otay Mesa/Center Road Station combination, the facility improvements amount to the sum of the improvements identified for each individual receipt point. As shown in Tables Q.6.1 and Q.6.3 above, $90 million in facility improvements is required for access on a displacement basis, and $220 million in facility improvements on an expansion basis at the assumed volumes. This result is due to the fact that both projects largely utilize separate facilities to reach ultimate load centers and for the most part serve separate load centers.

For the Otay Mesa/Salt Works Station combination, the facility improvements are greater than the sum of the individual improvements for each of the individual receipt points on an expansion basis, but they are the sum of each individual project cost on a displacement basis. Individually, both receipt points make use of the same existing transmission facilities to access the same load centers under this scenario. Transmission capacity is therefore insufficient for a scenario that assumes that significant volumes are delivered at both receipt points. In addition to the facility improvements shown in Tables Q.6.1 and Q.6.2, a new 36-inch diameter pipeline between Blythe and Needles on the SoCalGas system, and additional looping on Line 765, is required on an expansion basis. These additional improvements are estimated to cost approximately $135 million. Therefore, using the figures shown in Tables Q.6.1 and Q.6.2, $85 million in facility improvements is required under a displacement basis, and $410 million is required on an expansion basis under this scenario.

MAP Q.6.1 – CURRENT SDG&E GAS SYSTEM



MAP Q.6.2 – CURRENT SOCALGAS SYSTEM



NOT TO SCALE